consecutive monthly billing periods extending through the monthly period ending no later than five (5) months prior to the earliest possible auction commencement date. Utilizing a two (2) year period will reduce the variability of weather effects on the percentages from any single year. Should load profile data be unavailable for the 24 consecutive months prior to the initial auction, we will utilize the most recent 12 months of data.

Q. Please explain Table No. 2 of Resp. Exhibit 5.3.

A. Table 2 is a data input placeholder for percentage use during on-peak and off-peak periods that would be different from the 16 hour period discussed earlier in Table No. 1. Table 2 is necessary only if there is a need to use on-peak billing periods that differ significantly from those used for inputting of forward market prices, as discussed below. As stated earlier, the Ameren Companies' proposed on-peak billing hours are the same for the summer months and differ by one hour for the non-summer months. The slight shift of one hour during the non-summer months is not expected to have any material impact on the resultant pricing of the BGS services.

Q. Please explain Table No. 3 of Resp. Exhibit 5.3.

A. Table No. 3 is a data input table which contains the average energy usage in each monthly billing period based on energy delivered to each BGS service classification, as expanded for losses, for the Ameren Companies in the 24 consecutive monthly billing periods extending through the monthly billing period ending no later than five (5) months prior to the earliest possible auction commencement date. For illustrative purposes, in this filing, Table No. 3 is populated with historical calendar month sales of the Ameren Companies for the calendar year 2003, by month and by each proposed BGS rate classification at the bulk supply system level.

Q. Please explain Table No. 4 of Resp. Exhibit 5.3.

A. Table No. 4 contains the forwards prices for energy, by month and by time period (On-Peak and Off-Peak) corresponding to the applicable annual period for which retail supply charges are being determined. In this filing these forward prices are not necessarily the view of the Ameren Companies but, instead are meant to serve only as proxies to help facilitate or illustrate the results of the use of the Prism. We are proposing the following procedure for determining On-Peak and Off-Peak Energy Market Forwards prior to the initial auction and subsequent annual revisions.

A monthly Peak Energy Market Forward Price (PE_{mo}) and monthly Off-Peak Energy Market Forward Price (OE_{mo}) in dollars per megawatt-hour ($/MWh), will be determined from the market data from forward contracts for electric power delivered into the MISO's Central Illinois Hub from 6:00 a.m. to 10:00 p.m. Monday through Friday, excluding NERC holidays. Should the MISO energy market be delayed or develop more slowly than anticipated, we will utilize the Into Cinergy Hub as an alternative source. A separate PE_{mo} and OE_{mo} will be determined for each relevant calendar month in the respective BGS rate period. The Ameren Companies will use the Intercontinental Exchange reporting service or Platt's Energy Trader as the source of the market data, but may include additional or different electronic exchanges or reporting services in the future as allowed by the Commission. The market data will be obtained daily by the Companies from these sources' end-of-day reports to obtain a representation of the market for each of the forward contracts for the respective auction period. The market data will be obtained on each of the ten consecutive business days ending on or before the date ninety days prior to the earliest possible auction commencement date.

In the absence of market data for forward contracts with terms for individual months, market data for forward contracts with longer terms will be utilized. In the event no data exists for any given month in the off-peak period for which data is to be obtained, we will use ratios of actual off-peak to on-peak MISO locational marginal prices for the Ameren control areas for the most recent historical month corresponding to the month for which no forecast data exists. In the event that no data exists for any given month in the on-peak period for which data is to be obtained, we will use data for a more recent comparable month.

Q. Please explain Table No. 5 of Resp. Exhibit 5.3.

A. An adjustment of the forward prices contained in Table No. 4 must be corrected for the effects, if any, of transmission congestion on the MISO system between the MISO Central Illinois Hub and the Ameren zone where the BGS supply will be utilized. Table No. 5 contains an estimate of the average congestion factors, by month and by time period. Since the MISO system is in its infancy stages and thus has no useful history of such congestion, we have set this adjustment equal to "1"in this filing. The setting of this factor to "1"removes any consideration of congestion for this filing. We may, in subsequent annual revisions, include an estimate of the average congestion factor should such congestion in the MISO system become a known quantity. Approval of a charge in the average congestion factor would be sought from the Commission.

Q. Please explain Table No. 6 of Resp Exhibit 5.3.

A. Table No. 6 contains, for each of the Ameren Companies, the factors utilized for average distribution system losses and unaccounted for supply by proposed BGS rate schedule with adjustments to reflect delivery voltages. Currently, the loss factors are those shown in each of the Ameren Companies' applicable Delivery Services tariffs. Such loss factors are multiplied by metered customer usage to calculate the expected metered consumption at the bulk system level. Of course, these loss factors may be updated or adjusted from time to time as approved by this Commission.

Q. Please explain Table No. 7 of Resp. Exhibit 5.3.

A. Table No. 7 is the calculation of, for each of the Ameren Companies, the energy-only per unit costs by proposed BGS rate, time period, and season. These values are the seasonal and time period average costs per MWh as measured at the bulk system based on monthly time period weights from Table No. 1 and forwards prices from Table No. 4 as corrected for congestion (Table No. 5). These average per unit costs do not include the costs associated with ancillary services, generation obligations or transmission costs, which will be considered in subsequent calculations.

Q. Please explain Table No. 8 of Resp. Exhibit 5.3.

A. Table No. 8 indicates, for the Ameren Companies, the total value of the average BGS energy-only costs, by proposed BGS rate classification, time period and season. These values are the results from multiplying the unit costs from Table No. 7, the monthly time period weights from Table No. 1 and the total sales to customers from Table No. 3. These seasonal and rating period costs are used in Table No. 9 to calculate per unit costs at the customer's meter.

Q. Please explain Table No. 9 of Resp. Exhibit 5.3.

A. Table No. 9 shows the resulting Ameren Companies' composite rate class load weighted seasonal and TOD per unit energy-only costs at the customer's meter and are used to develop the rate multipliers and seasonal payment factors discussed later in this testimony. These values result from dividing the sum of each of the Ameren Companies' average BGS energy-only seasonal, TOD and total costs from Table No. 8 by the composite applicable seasonal, TOD, or total MWh use at the customer's meter.

Q. Please explain Table No. 10 of Resp. Exhibit 5.3.

A. Table No. 10 sets up the data necessary for the inclusion of the costs of the generation and transmission obligations. The top portion of Table No. 10 shows, for each of the Ameren Companies, the total obligations by proposed BGS rate classification. Over the years, the Commission has approved the use of peak loads for the allocation of fixed costs associated with generation and transmission assets. As a result, we utilized the average of the four summer coincident peaks for each class to allocate similar market-based fixed costs in this filing. The use of four coincident peaks does a fair job of recognizing the significant multiple peaks on the Companies' system. The middle portion of this table shows the number of summer and non-summer days and months that are used in this analysis. The bottom portion of this table shows the annual cost for transmission service and a seasonally differentiated market price of generation capacity. In this filing, the cost of transmission service is set to zero. It is our intent that the bid prices will exclude network transmission service and that these costs will be charged separately to retail customers through application of a new transmission cost recovery tariff that the Ameren Companies plan to file in their next DS rate filings. Currently, there is not a MISO capacity market in place; therefore, we are proposing to use an estimate of the current wholesale market prices for capacity in PJM as a proxy. The Ameren Companies will use MISO capacity market prices in the first filing of the Prism after such market exists.

Q. Please explain Table No. 11 of Resp. Exhibit 5.3.

A. Table No. 11 are the costs of ancillary transmission services to be included in the winning bid price. We proposes that ancillary services costs be based on averaging historical annual ancillary transmission services costs incurred in the provision of electric power supply for the 12 months ending no later than 90 days prior to the auction commencement date. Since there is no history of MISO ancillary costs, we have chosen, in this filing, to utilize the average $ per MWh ancillary services cost as determined by PSE&G in the most recent PJM auction which is meant to serve only as a proxy to help facilitate and illustrate the results of the use of the Prism.

Q. Please explain Table No. 12 of Resp. Exhibit 5.3.

A. Table No. 12 shows the result of the allocation of both transmission and generation costs on a per MWh basis to the proposed BGS rate classifications. These values are the result of, for each proposed BGS rate, dividing the sum of: (1) each of the Ameren Companies' average four coincident peaks from the upper portion of Table No. 10, multiplied by (2) the seasonal daily capacity price, multiplied by (3) the number of days per the seasonal period per the middle portion of Table No. 10, by the sum of each of the Ameren Companies' seasonal MWh at the customers' meters.

Q. Please explain Table No. 13 of Resp. Exhibit 5.3.

A. Table No. 13 contains the overall supply cost computation by rate classification, by summer and non-summer periods, and by on-peak and off-peak periods within those seasons as applicable. The top portion of Table No.13 is the resulting_BGS class load-weighted seasonal and/or TOD per unit costs and total system average load-weighted per unit cost of the inclusion of the transmission, generation capacity, and ancillary services costs to the energy-only costs shown in Table No. 9. These seasonal and time differentiated per unit costs become the numerator in the formulas that determine the multiplicative ratios in Table No. 14. Based on the assumptions utilized in the above tables, the bottom portion of this table shows, for each BGS service classification the total estimated "all-in" BGS costs to be recovered on an energy-only basis and the average per unit costs as measured at the customer meters or the bulk system.

Q. Please explain Table No. 14 of Resp. Exhibit 5.3.

A. This table is one of the most critical tables in the Prism. The upper portion of the table summarizes, for each BGS auction product, the total estimated costs of the BGS rate classes based on the inputs utilized in Tables 1-13 for each class and the resulting average "all-in"per unit cost measured at the customer meters and the bulk system. The middle and lower portions of this table is the resulting ratio (multiplicative factors) of each of the individual rate element cost components from Table No. 13, for each BGS rate class, to the overall all-in costs as measured at the bulk system from the top portion of this table.

Q. Please explain Table No. 15 of Resp. Exhibit 5.3.

A. Table No. 15 shows the calculation of the total BGS costs, by season utilizing the seasonal customer usage from Table No. 3, adjusted for losses from Table No. 6, and the all-in unit costs from Table No. 13. The lower portion of this table indicates the relative percentage of total costs by season and the overall average all-in seasonal unit costs on a dollar per MWh basis. The ratio of these overall average seasonal costs to the overall total costs from Table No. 14 are the seasonal payment ratios upon which seasonal payments to the winning bidders are based

Q. Please explain Table No. 16 of Resp. Exhibit 5.3.

A. Table No. 16 contains a reconciliation of the revenues recovered by application of the rate multipliers from Table No. 14 to the payment to suppliers based on the seasonal payment factors from Table No.15 and is used as a check of the Prism's operation.

Q. What is the next step in translating the single winning bid price from the auction processes into BGS rates for the respective customer groups?

A. The next step in the process is the determination of the Ameren Companies' average capacity and energy supply cost. The average cost is the weighted average price that would be paid to BGS suppliers accounting for seasonal payment factors and BGS sales volume by season. As discussed in Mr. Blessing's direct testimony, we are proposing, for the under 1MW (< 1,000 KW) customers, that the auction tranches have a three year term with 1/3 of the tranches expiring and being re-auctioned annually. The initial auction will have a 17-month, a 29-month, and a 41-month product. There will be a one year product for the large customer class BGS-4, except in the initial auction for which there will be a 17month product. Each year the auctions will be repeated so that the Companies can replace the expiring tranches from prior auctions. The clearing price for each of the three products (the current auction results with prior auction results) will be multiplied by the Companies' seasonal payment factors (those from current auction and those from prior auctions). These seasonal prices for each product will then be weighted by the associated number of tranches and seasonal sales volumes to determine the weighted average cost applicable to BGS load.

For example, assume that for the initial auction for the under 1MW customers: (1) the winning bid prices for the 17, 29 and 41-month products are \$40.00, \$41.00 and \$42.00 per MWh, respectively; (2) there are 60 total tranches bid, 20 tranches per product; (3) the seasonal payment factors per the initial Prism are 1.200 and

0.900 for the summer and non-summer respectively; (4) forcast BGS class MWh at the bulk system are 9,000,000 for the summer period and 14,000,000 for the non-summer period. The resulting weighted average bid price would be

$40 x 20/60 x 1.2 x 9,000,000 = $144,000,000

$41 x 20/60 x 1.2 x 9,000,000 = $147,600,000

$42 x 20/60 x 1.2 x 9,000,000 = $151,200,000

$442,800,000

$40 x 20/60 x 0.9 x 14,000,000 = $168,000,000

$41 x 20/60 x 0.9 x 14,000,000 = $172,200,000

$42 x 20/60 x 0.9 x 14,000,000 = $176,400,000

$516,600,000

$959,400,000

$959,400,000 ÷ 9,000000 + 14,000,000 = $41.71 per MWh

Continuing on, the following auction for the next BGS rate period will be 30 tranches for a 36-month product, at a winning bid price of $45.00 per MWh. The previous 17-month product is finished and there are 12 and 24 months remaining on the previous auction's 29 and 41-month products respectively. Assume: (1) the seasonal payment factors for the second auction per the Prism are 1.150 and 0.8750 for the summer and non-summer respectively and (2) BGS class MWh at the bulk system are 10,000,000 for the summer period and 15,000,000 for the non-summer period. The resulting weighted average bid price for the next BGS rate period would be:

$41 x 20/60 x 1.20 x 10,000,000 = $164,000,000

$42 x 20/60 x 1.20 x 10,000,000 = $168,000,000

$$\$45 \times 20/60 \times 1.15 \times 10{,}000{,}000 = \underline{\$172{,}500{,}000}$$

$$\$504{,}500{,}000$$

$$\$41 \times 20/60 \times 0.900 \times 15{,}000{,}000 = \$184{,}500{,}000$$

$$\$42 \times 20/60 \times 0.900 \times 15{,}000{,}000 = \$189{,}000{,}000$$

$$\$45 \times 20/60 \times 0.875 \times 15{,}000{,}000 = \underline{\$196{,}875{,}000}$$

$$\underline{\$570{,}375{,}000}$$

$$\$1{,}074{,}875{,}000$$

The new weighted average bid price that would be applicable to the next BGS rate period would then be:

$$\$1{,}074{,}875{,}000 \div 10{,}000000 + 15{,}000{,}000 = \underline{\$43.00} \text{ per MWh.}$$

This process would continue annually as the 12-month product would terminate and a new 36-month product would be auctioned.

The final step in the process is converting this resulting annual weighted average price into retail BGS rate values for the BGS rate period. This is accomplished by multiplying the weighted average bid price by the applicable rate multiplicative factors as determined by the Prism in Table No. 14.

For illustrative purposes, I have attached as Resp. Exhibit 5.5 a schematic or pictorial of the Prism, showing the inputs and other factors as described that result in the final price.

Q. Do the Ameren Companies envision the outputs of the Prism being used for other than rate development?

A. Yes. The BGS pricing spreadsheets are also intended to provide bidders with an easy to use tool that can translate auction prices for each term into retail BGS rates. Bidders can enter into the spreadsheet auction prices for the Companies' 3-

year and 1-year tranches, click on a calculate box and be able to view the BGS rates that would result if the auction were to clear at the entered price levels. BGS prices may be important to bidders for the purpose of assessing the likelihood and degree of migration to and from BGS rates.

It is contemplated that bidders may use these spreadsheets in two ways. First, in preparation for the auction, bidders can examine a wide variety of scenarios of potential auction clearing prices and analyze the retail rates that result from those scenarios. These analyses can be used to examine how potential migration from a given set of retail rates may affect the bidder's valuation of the auction opportunity. Second, as the auction is in progress, bidders will be able to enter going prices and update their analysis of potential migration and the auction opportunity. Also, as discussed above, Table No. 15 provides bidders with the seasonal factors for payments to bidders.

Q. Should one expect that billings generated under rates from the above-referenced prism achieve Ameren's goal of precisely recovering all costs associated with the procurement of said fixed power?

A. No. The decomposition of the single winning auction prices across several rate class and pricing periods based on predicted load characteristics and estimated losses, along with seasonal payment factors for remittance of payments to successful bidders, will result in under or over-collection of power costs. As a result, the proposed BGS Riders "point to" the previously mentioned Market Value Rider -Rider MV (Resp. Ex. 4.1).

Q. Please explain.

A. As discussed in Mr. Mill's direct testimony, Rider MV contains, among other items, the process for translating winning bid prices into BGS rates and an MVAF, which is an adjustment mechanism to synchronize BGS power supply costs to billed revenue. Mr. Mill provides additional detail on the rationale and the mechanics of the MVAF.

IV. <u>RIDER RTP – REAL TIME PRICING DISCUSSION</u>

Q. Mr. Cooper, please discuss Ameren's proposed RTP offering to customers with individual demands of greater than 1,000 kilowatts.

A. The proposed Rider RTP-L contains provisions for the availability of RTP to all customers with individual demands equal to or greater than 1,000 kilowatts (> 1MW). Additionally, we have designated RTP as the default power service for customers who either: (1) do not opt for BGS or RES service during the open enrollment period described in the testimony of Mr. Blessing or (2) lose RES supply for any reason.

Q. Please discuss the pricing of power under Rider RTP-L.

A. All energy purchased under Rider RTP-L will be priced based on provisions of the RTP-L bid contracts. These contracts contain three components for RTP-L service: (1) Energy at MISO Locational Marginal Hourly Prices ("LMPs") that vary by Ameren control area designation; (2) an energy based Rider D - Default Service Supply Availability Charge; and (3) a capacity based hourly demand charge. The proposed Rider MV contains the provisions for the pricing of these components. Of course, all of these charges will be adjusted for system losses.

Q. Earlier you mentioned Ameren's desire to have one set of prices for power and energy across its entire Footprint. Why are you proposing varying RTP related LMPs depending on which control area of Ameren's a customer is located?

A. Current MISO provisions do not allow the Ameren control areas to be treated as one "virtual" control area for LMP purposes. As a result, it is not possible to provide a single LMP for any hour that would be representative of the comparable hour LMP for each of Ameren's three control areas. Therefore, RTP customers will be subject to LMPs based on the control area of which they are located. Differences in LMPs among the Ameren control areas are primarily tied to transmission congestion costs and are expected to be minimal. Additionally, we are optimistic that in time MISO will treat the control areas as one and subsequent RTP related LMPs would be same for all of the Ameren Companies.

Q. Are any of the above mentioned charges for Rider RTP-L customers applicable to Rider RTP-L eligible customers with RES service?

A. Yes. Pursuant to the RTP-L bid contracts, the Companies are proposing that all Rider RTP-L eligible customers with RES service be subject to the non-bypassable Rider D.

Q. Please explain.

A. RTP-L power and supply bidders have included a Rider D charge or component on a cents per kilowatt hour basis for all Rider-RTP-L load and all Rider RTP-L eligible load with RES service. As stated earlier, we propose to bill this charge on a cents per kilowatt hour basis, as adjusted for losses, to all Rider RTP-L customers and Rider RTP-L eligible customers with RES power service.

Q. Please discuss the proposed RTP offering to customers with individual demands of less than 1,000 kilowatts (< 1 MW).

A. The proposed Rider RTP contains provisions for the availability of RTP to all customers with individual demands of less than 1,000 kilowatts. Unlike terms for customers with individual demands of 1,000 kilowatts or greater, the Companies have designated BGS the default power service for customers with individual demands of less than 1,000 kilowatts.

Q. Please discuss the pricing of power under Rider RTP.

A. All energy purchased under Rider RTP will be priced under Rider MV. Essentially, small customers opting for this service will receive "virtual" or equivalent billing under proposed Rider RTP-L, as described above, excluding the Rider D charge.

Q. Please elaborate.

A. As discussed in the testimony of Mr. Blessing, the Companies will not request bids for RTP power for customers with individual demands of less than 1,000 kilowatts. However, the Companies propose that these customers be billed as if they were served under Rider RTP-L without the imposition of Rider D charges for customers within this category who do opt for RES service. Therefore, Rider D charges will only be applicable to customers opting for RTP service. The rationale for omitting Rider D charges for RES-served customers in this category lies in the defaulting of these customers to BGS versus RTP. The bid price for

BGS for all customers in this class should include a component for the defaulting of this service to BGS; the inclusion of Rider D on RES served load in this category would suggest a "double counting" of sorts.

V. SWITCHING RULES DISCUSSION

Q. Will customers eligible for the various BGS service offerings be subject to switching rules?

A. Yes. There is a direct correlation between auction bid price and switching and minimum stay requirements for customers with choices between utility provided power and service from a RES. Typically, the greater the load uncertainty, the greater the probability that suppliers will be compelled to add larger risk premiums to offset risks. However, there are concerns that the existence of switching and minimum stay rules may impede the development of the power market. The following switching/minimum stay rules should strike a reasonable balance between the goals of supporting the development of a robust power market and, at the same time, obtaining the lowest possible market prices for customers. The proposed Rider MV tariffs contain the applicable switching rules.

VI. TRANSMISSION SERVICE DISCUSSION

Q. You have now discussed the proposed post-2006 power service offerings. Please discuss the Companies' plan for Transmission Service offerings.

A. The Companies plan to file a Transmission Service Rider – Rider TS with their next Delivery Service case. This rider will contain all provisions for the providing of transmission service to customers opting for power service from the Companies' post-2006 and will provide for full recovery of all costs, fees, and charges for transmission and related services not otherwise recovered under the BGS or RTP riders. This rider is not expected to apply to customers taking service from a RES.

VII. OTHER POWER SUPPLY DISCUSSION

Q. What are you proposing for power sales to customers with non-emergency self-generation that operates in parallel with the Ameren Companies?

A. We are proposing that customers with self –generation capacity of less than five (5) megawatts be offered power service under either Rider BGS or Rider RTP. This proposal provides customers with small to medium sized self generation units the flexibility of selecting applicable BGS or RTP power service simultaneous with full flexibility in operating their generators in a manner consistent with their internal economics. Based on initial customer survey intelligence, it is anticipated that the aggregate capacity of self generation in this category represents approximately five (5) percent of total non-emergency customer self generation installed on the Ameren Companies.

Q. What are you proposing for power sales to customers with non-emergency self-generation equal to or greater than five (5) megawatts that operates in parallel with the Ameren Companies?

A. We are proposing that customers with self –generation capacity equal to or grater than five (5) megawatts be offered a "hybrid" of power service under Rider BGS and Rider RTP or, in the alternative RTP, only.

Q. **Please explain the proposed hybrid Rider BGS and Rider RTP power offering for these customers.**

A. Customers with non-emergency self-generation at these levels tend to be very sophisticated energy managers. In some cases, these customers utilize excess steam from product process operations to run in house generator sets. We are proposing that customers in this category be subject to a hybrid billing that: 1) adequately reflects the costs of providing power service to their unique operations, 2) provides proper price incentives with regard to whether self installed generation output is more economic than market based RTP, and 3) minimizes the opportunity for these customers to place low load factor load on the system at prices that don't reflect actual market prices.

Q. **Please elaborate.**

A. First, customers in the above category will be required to pay the Ameren Companies for the installation of metering or install, at their own costs, acceptable metering for measuring the output of their generators. Additionally, standard metering for the billing of the Companies' DS, BGS, and RTP services will be required. The hybrid proposal will bill all Company metered power usage in excess of that that could be hypothetically served by the customer's self generation at a one-hundred percent capacity factor under the applicable Rider BGS fixed price product. However, any Company metered power usage metered during intervals where the customer's generator is operating at less than one-percent capacity, will be billed under the applicable RTP. While this approach is somewhat complex, billing can be easily accomplished by a comparison of the interval meter reads between the customer's generation meter and the customer's DS, BGS, and RTP power meter. Additionally, this hybrid billing addresses the three concerns mentioned above and is just and reasonable. Based on initial customer survey intelligence, it is anticipated that the aggregate capacity of self generation in this category represents approximately ninety-five percent of total non-emergency customer self generation installed on the Ameren Companies' system. Additionally, this hybrid billing proposal provides a proper balance between the customer's desire to economically operate self generation and our desire to have power prices that reflect cost causation and equitable cost recovery principles.

Q. What are you proposing for power and energy sales to customers desiring power service from the Ameren Companies to supplement or augment power being provided by an ARES?

A. We are proposing that customers desiring power and energy from Ameren to supplement or augment power provided from an ARES be served under the applicable RTP offering. The application of the RTP offering for supplementing or augmenting power and energy provided by a ARES is reasonable considering a primary criterion (i.e., homogeneous load or usage characteristics) in establishing rate design for the Company's fixed price offering. A customer obtaining power and energy service from a RES may be homogeneous with the other ARES or Company customers from a load perspective, however, its use of power and energy service from an ARES versus that served by one of the Companies could vary significantly. For example, if we were to offer the fixed price product to these participants in the market, one would expect that, wherever possible, they will place load swings or peaks during periods of high costs on our system at a fixed price, while base loading on the ARES at a lower per unit price. The use of RTP for power and energy service required to supplement or augment ARES service minimizes the likelihood of these customers behaving in this manner, prevents subsidies to the detriment of our fixed price customer groups, and sends a better or more proper price signal. Thus, the use of RTP for this service is just and reasonable, and also promotes the development of an efficient market for power and energy.

Q. Earlier you mentioned that the Ameren Companies would be filing DS cases for new rates to become effective prior to the effective date of the post-2006 BGS offerings. Please discuss the basic objectives of your delivery services filings as they may relate to BGS.

A. The objectives of the DS filings are as follows: (1) complete recovery of the Ameren Companies' DS related revenue requirements; (2) alignment of DS classes with BGS/RTP classes; (3) class revenue requirements and rate design that reflect cost causation and equitable cost recovery principles; (4) competitively neutral DS rates (i.e., rates for DS should be the same whether customer opts for virtual bundled service from the Ameren Companies, or takes DS from the Companies with power from an ARES. Achievement of these DS objectives will assist in promoting a robust retail market for power in Illinois, promote ease of customer and employee understanding of our rates and tariffs, and provide our shareholders with a reasonable rate of return. As a result, all stakeholders benefit.

Q. Have you prepared an exhibit that maps the Ameren Companies' existing bundled retail electric Service Classifications to expected post-2006 DS, TS, and BGS/RTP applications for the continuation of "virtual" bundled service?

A. Yes. Resp. Exhibit 5.4 contains this mapping for the Ameren Companies' classifications.

Q. Will customers defaulted to BGS-1, 2, and 3 on January 2, 2007, be required to remain on such for an entire year?

A. No, we recognize that despite the efforts of all the parties in this process to educate consumers prior to January 2, 2007, there will still be some confusion, especially with smaller customers. As a result, all customers initially defaulted to BGS 1, 2, or 3 may switch to any other available BGS rates at any time subject only to DASR requirements.

Q. Please discuss your proposed BGS treatment for new connections/customers post-2006.

A. All "new" (i.e., customers served from new distribution extensions or successor customers) customers will be given the option of either BGS "fixed" price or RTP service, if they request power service from the Ameren Companies.

Q. Does this conclude your direct testimony?

A. Yes, it does.